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THESIS

UTILITY COST ACCOUNTING AND
MARKET PRICING OF ELECTRICITY
AT THE NAVAL POSTGRADUATE SCHOOL

by

Michael J. Murdter

June, 1994

Advisor: David R. Henderson

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The current invoice processing procedures were analyzed and spreadsheet tools were developed to streamline the processes and avoid interest charges from late payment.

The results of the research indicate that market pricing of electricity and accelerated invoice processing would result in significant savings to the Naval Postgraduate School.

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by

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ABSTRACT

This thesis demonstrates that significant cost savings may be realized at the Naval Postgraduate School by accounting for utilities costs with market pricing methods instead of engineering estimates of consumption for nonmetered users and by streamlining the current invoice processing procedures.

Electricity demand curves for each element of the supplier rate structure were constructed from recent consumption data and price elasticities of demand from the literature. The deadweight losses from overconsumption were calculated and compared to the costs of installing meters capable of recording time-of-use and peak demand.

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The results of the research indicate that market pricing of electricity and accelerated invoice processing would result in significant savings to the Naval Postgraduate School.

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LIST OF ACRONYMS

AAA	Authorization Accounting Activity
BRDENTAL	Branch Dental Clinic
BTU	British Thermal Unit
CAL-AM	California American Water Company
COMO	Commissioned Officers Mess, Open
DEIS	Defense Energy Information System
DFAS	Defense Financing and Accounting Service
DHRSC	Defense Health Resources Study Center
DIS	Defense Investigative Service
DLA	Defense Logistics Agency
DMDC	Defense Manpower Data Center
DPS	Defense Printing Service
DRMI	Defense Resources Management Institute
DWL	Deadweight Loss
FAA	Federal Aviation Administration
FHN&MC	Family Housing Navy and Marine Corps
FNOC	Fleet Numerical Meteorology and Oceanography Center
GC	Golf Course
ISA	Intraservice or Interservice Support Agreement
JON	Job Order Number
LMV	La Mesa Village (Officer Housing area)
MPTV	Monterey Peninsula Television
MRWPCA	Monterey Regional Water Pollution Control Authority
MWR	Morale, Welfare and Recreation
NAF	Non-appropriated funds
NAVCOMPT	Office of Comptroller of the Navy
NCIS	Naval Criminal Investigative Service
NEX	Navy Exchange

NGC	Natural Gas Clearinghouse
NPS	Naval Postgraduate School
NRL	Naval Research Laboratory
O&M,N	Operations and Maintenance, Navy
OPTAR	Operating Target
PERSEREC	Personnel Security Research Center
PG&E	Pacific Gas and Electric Company
PPA	Prompt Payment Act
PSD	Personnel Support Detachment
PW	Public Works Department
ROICC	Resident Officer in Charge of Construction
SOQ	Senior Officers Quarters
STARS FL	Standard Accounting and Reporting System - Field Level
TRADOC	Training and Doctrine Analysis Command (Army)
WESTDIV	Western Division, Naval Facilities Engineering Command

I. INTRODUCTION AND PROBLEM BACKGROUND

A. INTRODUCTION

The Naval Postgraduate School (NPS) purchases electricity, natural gas, water, cable television, sewage disposal and refuse collection services for NPS departments and tenant commands on the main station and other satellite areas at an annual cost of approximately $3.2 million per year. For electricity, natural gas and water services, the total NPS usage is determined by meters owned by the utility companies.[1] The costs for these services must be allocated among all users[2] to enable NPS to be reimbursed by tenant commands and to track costs that must be paid for with specific appropriations such as housing funds. This thesis examines the existing utility cost accounting and invoice processing procedures used by the NPS Public Works (PW) and Comptroller departments. It specifically focuses on evaluation of the existing cost allocation methods and ways of automating and streamlining the existing procedures.[3]

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[1]Many facilities on the main station are heated with steam produced by the Public Works boiler plant. The boilers normally burn natural gas (although the plant has the capability to burn fuel oil in the event of a natural gas outage). Therefore, steam is not addressed here as a separate utility because the energy costs of heating the facilities are reflected in the natural gas costs.

[2]A "user" is any entity or organization whose utility costs are tracked and paid separately. A user may be a tenant command (including those organizations that lease private facilities such as DMDC and PERSEREC), or a department or division of NPS whose utilities are paid for with other than O&M,N funds (such as housing or NAF activities). See the List of Acronyms right after the Table of Contents for an explanation of each acronym.

[3]The reader is assumed to have a working knowledge of basic Navy financial management and contracting procedures and terminology. Additional explanation is included in the text where necessary to clarify those procedures as they apply to the subject matter.

The cost accounting for utilities involves a number of steps, including the establishment of reimbursable accounts for tenant commands based on their Intraservice or Interservice Support Agreement (ISA) with NPS; the preparation of estimates of future utility costs upon which departments and tenants budget and establish obligations (set aside funds); receipt, review and certification of invoices, including the allocation of costs among the various users or paying entities; adjustment of differences between the cost estimates and actual charges; and the assignment and tracking of various document numbers and accounting data, such as job order numbers (JONs) that accompany the cost figures. Both the Public Works Department and the Comptroller Department are involved in the execution of these functions, a more detailed discussion of which is contained in Chapter II.

Accurate accounting for utilities costs is important for the following reasons:

1) It is extremely important to avoid an overobligation of funds, that is, spending more money than has been appropriated. The differences between the estimates and actual charges must be closely tracked to ensure that sufficient funds are available or can be made available to cover all costs in the fiscal year to avoid violating the Anti-Deficiency Act (31 US Code 1517).

2) The correct fund appropriation must be used. For example, housing funds, nonappropriated funds, and Operation and Maintenance, Navy (O&M,N) funds must be charged in the right amounts. If NPS were inadvertently to pay for housing utility costs with O&M,N funds instead of Family Housing Navy and Marine Corps (FHN&MC) funds, it would violate 31 US Code 1301(a).

3) The various paying entities should pay their fair share of the bill. Each command must meet its mission with a limited amount of funds, and therefore an overcharging of utility costs to that command reduces the funds available for other purposes and adversely affects the ability of the command to meet its mission. Since utility costs are a significant portion of most commands' available funds, this issue is significant.

B. GENERAL COMPLICATING FACTORS

The existing cost accounting and invoice processing procedures are complicated by a number of general factors and factors specific to each utility. A discussion of these factors follows.

1) Large number of invoices. NPS receives multiple invoices for each utility each month for a total of 18 invoices per month (Appendix 1, Col. 1). The multiple invoices are the result of changing contractual arrangements over the years, multiple suppliers and the dispersal of user facilities over the following areas:

- NPS Main Station
- Navy Annex (including Golf Course)
- La Mesa Village Housing Area
- DMDC/PERSEREC at 99 Pacific Street, Monterey

2) Short time frame allowed for processing of invoices. Utility contracts are often not subject to the Prompt Payment Act (which generally requires payment

within 30 calendar days of receipt of a proper invoice) but to the terms of the individual contract. In the case of many NPS contracts, payment is required within 15 calendar days, which includes the certification of the invoice, mailing to the Authorization Accounting Activity (AAA) in Crystal City, Virginia, and preparation of the check by the AAA. The AAA serving NPS requires a minimum of seven calendar days to prepare checks on certified invoices but currently takes more than 15 days. Therefore, NPS is working in a deficit time-wise from the moment the invoice is received. NPS faxes a copy of the certification (NAVCOMPT Form 2035) to the AAA as soon as it is complete, but, even if the AAA could process it in seven calendar days or so, NPS would have only eight calendar days (six working days) to complete its work to meet the 15- day requirement.

One consequence of this problem is that invoices usually show not only the current charges but the unpaid balances as well (for previous invoices that have been processed by NPS but payment for which has not been received by the supplier by the current invoice date). This requires extra processing time to ensure that charges are not paid twice.

The accounting technician must be aware of the time allowed for processing of the specific invoice on her desk at the moment. For example, of the three sewage bills, two are required to be paid in 20 days and one is required to be paid in 30 days (Appendix 1).

3) Budget estimates. The Public Works Fiscal Division is required to prepare budget estimates for all users but has limited ability to accurately estimate costs for

electric, gas and water service for future periods. The only estimating tools available are historical data on usage, adjusted for any subsequent changes in rates. Unless the user informs PW of events that increase or decrease consumption (e.g. installation of a new computer system or additional air conditioning, changes in facility operating hours, etc.), or PW happens to know of these events because it was involved in the project, the Fiscal Division has no basis for adjusting the budget estimates. Nonmetered users have a disincentive to notify PW of increased usage because it could raise their fixed bills. Higher-than-estimated usage causes problems for every user not on a fixed-charge basis because it reduces confidence in the estimate and hinders smooth budget execution.

Weather is one of the biggest factors outside the control of the Fiscal Division. Unseasonably warm or cool weather can adversely affect the accuracy of the budget estimates.

Further hindering the ability of the Fiscal Division to produce accurate budget estimates is the fact that the number of days in a billing period varies because the utility companies do not all read their meters on the same day each month. For example, PG&E billing periods range from 25 to 37 days. Also, the electricity cost per kilowatt-hour (kWh) changes with the time of year as does the definition of peak, partial-peak and off-peak hours, further complicating the estimating procedure.

Estimating charges for the other services (refuse, cable TV, etc.) is relatively easy. Unless a change in service is ordered or the cost allocation scheme is changed,

the costs to each user are the same each month because the contracts have fixed unit prices and quantities.

4) Administrative resources available. PW Fiscal Division has only one GS-6 Accounting Technician to handle all utility cost accounting and invoice processing functions. Seventy percent of her time is devoted to utilities issues; the other 30 percent is for unrelated duties.

5) Availability of funding obligations. PW cannot certify invoices until funding obligations and authorizations have been entered into the accounting system.[4] PW must often hold the invoice while waiting for obligations to be entered. This occurs primarily because tenants frequently are late getting their funds to the Comptroller.

6) Large amount of related accounting data (e.g. JONs, serial numbers) that is associated with each separate cost element. This routine data is required to fully identify the expenditure with respect to its appropriation, fiscal year, type, etc. in accordance with standard Navy financial management procedures. Management of this data requires a substantial portion of the accounting technician's time.

7) Time lag between consumption and billing. It is often months between the time utilities are consumed and the time invoices arrive for processing from the supplier. This time lag hinders smooth budget planning and execution. The time lag takes on increased significance at the end of the fiscal year, when the utility accounts must stay open until the invoices arrive. Underobligation means that additional

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[4] An obligation is a legal encumbrance, or setting aside, of a specified sum of money which will require outlays or expenditures in the future. The Comptroller establishes obligations by making appropriate entries into the accounting system. An authorization, as used here, is when the Comptroller formally authorizes a department to incur obligations.

prior-year funds must be obtained to cover the difference; overobligation means that funds that could have been used for other purposes were tied up and subsequently expired.

C. SPECIFIC FACTORS WITH RESPECT TO ELECTRIC, GAS AND WATER

Allocating the cost of these utilities among the various users is complicated by the following factors:

1) Large number of users among whom the costs must be allocated (Appendix 2). Not only do tenants pay their share, but costs for certain NPS departments must be broken out separately (e.g. housing, golf course, COMO) because they are paid with different appropriations. Related to this problem is the fact that many users have multiple facilities spread out over the NPS complex, each with its own particular metering situation. The result is that the PG&E summary bill for the main station, for example, must be broken down into 26 lines of accounting data (Appendix 1, Col. 5)

2) Wide variety of metering arrangements. Some users have their own meter(s) and so charges for those meters are separately identifiable on the invoice. Other tenants either share meters, in which case a cost-sharing formula must be used, or are not metered, in which case some sort of estimated usage must be developed. This issue is discussed in more depth under "Cost Allocation Methods" below.

3) Large number of PG&E accounts (with at least one meter per account) and contract numbers (related to the dispersal of NPS and tenant facilities). NPS

(including all users) has 24 contracts with PG&E covering 54 accounts and over 60 electric and gas meters. PG&E has taken steps, at NPS request, to simplify the electric and gas invoices by producing four "summary billings" roughly corresponding to the four geographical areas of NPS and tenant operations described above.

4) Multiple electric rate structures.[5] Each account is charged according to its PG&E-assigned rate structure. PG&E determines which of its five commercial/industrial rate structures[6] to assign based on the annual demand for the account. In the case of NPS, all five rate schedules are used to cover the 54 accounts. Obviously, there are multiple meters on the same rate schedule. The five rate schedules are summarized below. Note that even for similar types of charges the method of calculation varies widely depending on the rate schedule:

A-1 Commercial non-time-of-use. The monthly charge for service under Schedule A-1 is the sum of a customer charge and energy charges only (no demand charges):

- The customer charge is a flat monthly fee per meter according to the type of meter (single-phase or polyphase service).
- The energy charge is a flat rate per kilowatt-hour (kWh) according to the time of year (summer or winter) but not the time of day.

[5] All main station PG&E accounts are on the same natural gas rate structure with the exception of Quarters B, which usage is negligible.

[6] PG&E also has a set of residential rate structures which are applied to the La Mesa Village (LMV) officer housing area. The residential rates are not discussed here because they do not complicate the cost allocation process since LMV is metered separately.

A-6 Commercial time-of-use. The monthly charge for service under Schedule A-6 is the sum of a customer charge, a meter charge and an energy charge:

- The customer charge is the same as under Schedule A-1.
- The meter charge is a flat monthly fee per meter.
- The energy charge is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour, and rates are differentiated according to time of day and time of year.

A-10 Medium General Demand-Metered Service. The monthly charge for service under Schedule A-10 is the sum of a customer charge, demand charges and energy charges:

- The customer charge is a flat monthly fee per meter.
- The demand charge is a flat rate per kW times the maximum demand each month. The number of kW consumed is recorded over 15-minute intervals; the highest 15-minute average in the month is the customer's maximum demand.
- The energy charge is a flat rate per kilowatt-hour according to the time of year (summer or winter) but not the time of day.

E-19 Medium General Demand-Metered Time-of-Use Service. The monthly charge for service under Schedule E-19 is the sum of a customer charge, demand charges and energy charges:

- The customer charge is a flat monthly fee per meter.
- There are three demand charges, a maximum-peak-period demand charge, a maximum partial-peak-period demand charge and a maximum-demand charge. The maximum-peak-period demand charge per kilowatt hour applies to the

maximum demand during the month's peak hours, the maximum partial-peak-period demand charge applies to the maximum demand during the month's partial-peak hours, and the maximum demand charge applies to the maximum demand at any time during the month. The bill includes all three of these demand charges.

- The energy charge is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour, and rates are differentiated according to time of day and time of year.

E-20 Customers with Maximum Demands of 1,000 kW or More. Schedule E-20 contains the same type of charges as Schedule E-19 but with different unit prices.

5) Multiple natural gas suppliers. Gas is purchased from two sources: PG&E, for the Navy Annex, La Mesa Village, and parts of the main station and, through the Defense Logistics Agency (DLA), from the Natural Gas Clearinghouse, for parts of the main station only. PG&E-purchased gas appears on the PG&E summary bills, along with the charges for electricity. Although NPS buys gas from NGC, a transport fee must still be paid to PG&E, the owner of the gas lines. This transport fee for gas purchased from NGC appears on the PG&E bill, not the NGC bill, and must be allocated among gas users. The PG&E transport charges consist of:

- A monthly customer charge, which is based on a sliding scale according to the average monthly amount of gas (in therms[7]) transported

- A flat fee per therm of gas transported and distributed, depending on the time of year.

[7]Natural gas is measured in therms, which are units of heat (1 therm = 100,000 BTU), instead of by volume because the heat content of gas per unit of volume varies.

The NGC bill arrives several months after the month in which the billed gas was consumed, and contains a charge for gas consumed and a charge for "imbalance adjustment", which is essentially the cost of gas purchased to fulfill NPS requirements above the base quantity specified in the DLA contract for NPS. (If NPS were to use less than the base amount, the surplus gas can be sold by DLA to others within a certain window of opportunity of about three weeks.) This dual-sourcing of natural gas suppliers requires additional meter reading and administrative effort.

In summary, the existing data environment contains many wrinkles and quirks that the cost accounting and invoice processing procedures must deal with individually. There is not a homogenous mass of data whose sheer quantity is the problem, but a relatively small amount of highly differentiated data.

D. COST ALLOCATION METHODS

The above factors contribute to the difficulty of devising a cost allocation method for electric, gas and water service that minimizes the "deadweight" loss. A deadweight loss results from the overconsumption that may occur when a user is not charged for the full cost of the utility. For example, if a user is charged a fixed dollar amount or a fixed percentage of the total bill for electricity, the user may consume more electricity than if it were metered because the cost of additional units consumed is spread over all users. Each non-metered user is in effect subsidized by all other users. The existing cost allocation method is discussed and critiqued below.

1) Any user occupying a facility having its own PG&E meter and who is the sole occupant of the facility simply pays the charge as shown on the PG&E bill for that meter (e.g. DMDC). If two or more users occupy a PG&E metered facility, the charges are prorated as agreed upon by the users, usually on a square-footage basis (e.g. FNOC/NRL).

2) For users not served by a PG&E meter but served by a Navy-owned meter "downstream" of the PG&E meter, actual usage can be determined if the Navy meter is read the same day as the PG&E meter "upstream" to allow comparability over the same time period. However, the Navy meters are capable of measuring usage only, without regard to time-of-use. Therefore, using the Navy meter to prorate charges carries the implicit (and reasonable) assumption that the proportion of the total usage consumed during each rate period (peak, partial peak and off peak) by the Navy-metered user is the same as for the PG&E meter as a whole. If two or more users occupy a Navy-metered facility, the charges are prorated on an agreed-upon basis.

3) For users whose facilities are not served by PG&E or Navy meters, an engineering estimate is used. The existing method used is to divide the total utility cost for the previous year by the total square footage of NPS facilities to obtain a fixed cost per square foot per year. This figure is multiplied by the total square footage of the user-occupied space and divided by 12 to arrive at a fixed monthly charge. For example, if the total annual cost for electricity were $2,400,000 and the total square footage of NPS facilities were 1,000,000 SF, the fixed cost/SF per year

would be $2.40. If a user occupied 2,500 SF, its fixed cost would be $6,000/year or $500/month.

4) After subtracting the charges for all metered users and the fixed charges for non-metered users from the invoice total, NPS pays the difference with O&M,N funds.

On the positive side, fixed charges for non-metered users:

- Simplify the cost allocation.
- Allow users to plan and execute their utility budgets easily.
- Equalize several factors that affect utility consumption but over which the tenants, who are assigned NPS-owned facilities, have little or only partial control, such as the energy efficiency of their work spaces (due to the type of lighting, insulation value of windows and walls, etc.) or the efficiency of the utility distribution system serving their spaces. In other words, a user's total consumption could vary simply because of the workspaces assigned by NPS, and fixed charges tend to "smooth out" these differences.

On the down side, fixed charges:

- Mean users with a high intensity of usage (e.g. computer center) pay the same amount per square foot as a user with low intensity (e.g. Barbara McNitt Ballroom in Herrmann Hall).
- Result in the largest deadweight loss because there is little incentive to conserve electricity.
- Do not differentiate between users on different rate schedules or those on time-of-use schedules who consume proportionally more during the more expensive on-peak period.
- Result in NPS paying the difference if the total annual charges are higher than the amount used to calculate the per-square foot cost.

The economic consequences of using engineering estimates of utility consumption versus metered quantities is discussed at length in Chapter IV, including evaluation of various alternative cost allocation methods. In any event, it will be necessary to develop spreadsheet and/or database tools to allocate costs based on the existing method, then alter those tools to handle whatever new cost allocation scheme is devised and adopted.

E. THESIS METHODOLOGY

The methodology used to analyze the topic of this thesis is as follows:

1. The existing cost accounting and invoice processing procedures, including the method of allocating costs among nonmetered users, were examined to uncover the factors that complicate the process and document the resulting problems. The existing utility distribution systems and meter locations were examined and the meter serving each utility user was determined. Chapter I provided a broad overview of the problem and outlined the complicating factors. Chapter II illustrates the existing procedures.

2. Next, spreadsheet tools were developed to simplify the invoice processing and management of data needed to meet reporting requirements. Chapter III discusses the development of these tools.

3. The deadweight loss issue was examined in depth by constructing demand curves using recent consumption data and elasticities of demand from the literature. The deadweight losses were then calculated for the existing and two alternative cost allocation methods and compared against the methods' implementation costs. Chapter IV contains a comprehensive analysis of the deadweight loss issue.

4. Revised procedures were developed based on the tools developed in Chapter III and the knowledge gained from the deadweight loss analysis. The revised procedures are discussed in Chapter V. Chapter VI summarizes the thesis findings and provides recommendations.

II. EXISTING COST ACCOUNTING AND INVOICING PROCEDURES

A. INTRODUCTION

The cost accounting and invoice processing procedures should accomplish three main functions:

1. Pay the utility supplier in a timely manner and in the correct amount.

2. Properly account for utility costs, to include:

- Provide a basis for obligations to be entered into the accounting system using the correct appropriation so utility charges can be accrued, thereby avoiding unauthorized commitments.
- Accurately allocate costs among all users.
- Adjust obligations to reflect actual utility costs

3. Track data elements to satisfy audit requirements and produce required reports.

This chapter will examine the existing cost accounting and invoice processing procedures by tracing the path of an invoice from receipt to certification.

B. EXISTING PROCEDURES

The existing procedures are shown in Appendix 8 and summarized as follows:

1. Public Works Fiscal Division prepares estimates of annual cost for each utility for each user. Fiscal also estimates utility costs for the upcoming month and forwards these estimates to the Comptroller by the 10th of the month. The

Comptroller records obligations in the amount of the estimates in the official accounting system, called the Standard Accounting and Reporting System - Field Level (STARS FL).

2. Fiscal notifies each user of their annual utility cost estimate. Users send funds to the Comptroller.

3. The Comptroller assigns JONs and a range of serial numbers for each user.

4. When an invoice is received, Fiscal examines it for any irregularities (e.g. prior or unusually high charges, missing or incorrect account billings, etc.).

5. After irregularities are corrected, costs are allocated based on the fixed-charge method discussed in Chapter I. Calculations are done manually for the most part.

6. If all users have sufficient funds remaining to cover the current charges, Fiscal prepares the invoice certification. If any users do not have sufficient funds on hand, Fiscal notifies the user(s) of the funding deficiency but "covers" them so as not to delay processing of the invoice.

7. Fiscal prepares a NAVCOMPT 2035 invoice certification. Fiscal performs the cost certification of the invoice (i.e. certifies that the quantities stated in the invoice were received during the period stated in the invoice and that funds to cover the charges shown are available). The PW Administrative Officer then performs the technical certification (i.e. certifies that the technical provisions of the contract have been complied with and that the rates cited in the invoice are correct.)

8. A copy of the invoice certification is forwarded to the Comptroller. The Comptroller adjusts the obligations to reflect the actual costs. Fiscal checks the STARS FL system to ensure that the obligations have been adjusted before sending the invoice certification to the AAA.

9. The certified invoice is sent to the AAA for payment.

The NPS Command Evaluation Officer performed reviews of Public Works utilities cost accounting and invoice processing procedures in early 1994. Problems identified include:

- Late payments to utility suppliers
- Erroneous charges (users being charged the wrong amount or not at all)
- Inadequate accrual of utility costs due to poor budget estimates. In other words, the actual charges differ significantly from the obligations due to poor budget estimates.
- Lack of incentive to save energy due to the current flat-rate (fixed-charge) method of cost allocation

Although the factors outlined in Chapter I contribute to some degree to the above problems, there are a number of steps that may be taken to help solve them, including:

- Developing a method of preparing more accurate utility budget estimates by analyzing historical consumption patterns. This issue is discussed in Chapter III.
- Developing a spreadsheet to handle some of the "number crunching" tasks, including calculating the budget estimates, allocating charges among users and preparing periodic reports. Automating the process in this way should speed up invoice processing and improve accuracy. This topic is also discussed in Chapter III.
- Performing an economic analysis of the existing cost allocation method and alternative methods. Chapter IV examines this issue in depth.
- Reassigning responsibilities for certain steps of the cost accounting and invoice processing procedures to take full advantage of the capabilities of the Public Works and Comptroller departments. This issue is addressed in Chapter V.

III. SPREADSHEET AND DATABASE TOOLS

A. INTRODUCTION

This chapter discusses the development of personal computer spreadsheet and database tools to handle the three biggest utility data processing tasks:

- Preparing budget estimates of utility costs
- Allocating invoice charges among users
- Preparing periodic reports

Borland International's QUATTRO PRO 4.0 software was used for these applications because it is the standard spreadsheet software for the Public Works Department.

B. PREPARING BUDGET ESTIMATES OF UTILITY COSTS

Chapter I discussed the difficulty of producing accurate budget estimates of utility costs. Figure 1 shows the electrical energy consumption (in kWh) of the largest main station NPS account[8]. Note that the monthly usage fluctuates greatly and that there is no discernible pattern between summer and winter consumption.[9] Furthermore, there is a general trend of lower usage from 1990 to 1991 but higher

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[8] Data was obtained from PG&E.

[9] Although the energy consumption varies widely from month to month, the peak power demand is consistent at about 2620 kW. The significance of this fact is discussed in depth in Chapter IV.

usage from 1991 to 1993. Based on this trend it appears that using pre-1993 consumption data to project future costs would result in budget estimates that are too low. More recent data should be used.

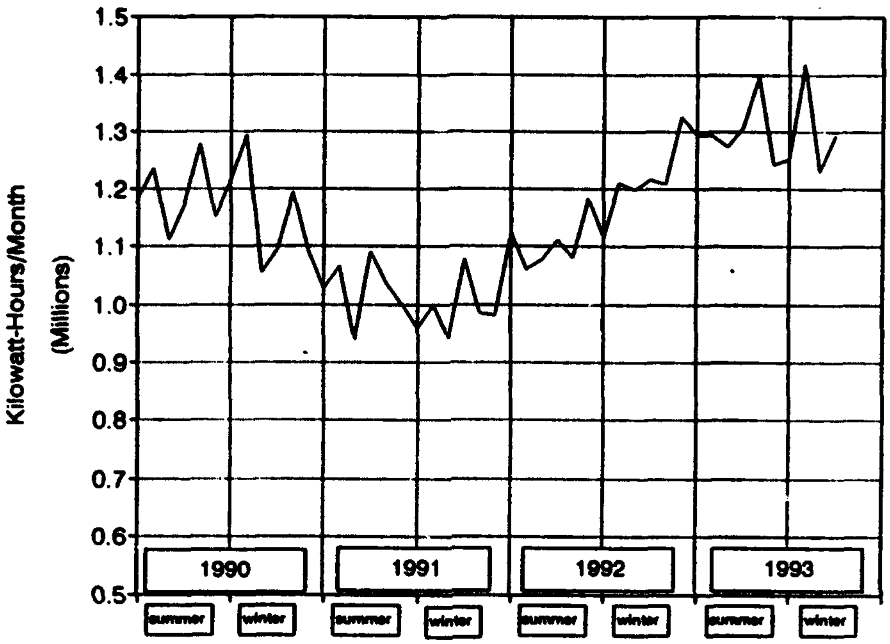

Figure 1 NPS Electrical Consumption

It therefore appears that a good estimating method for the upcoming month would be to take the average monthly usage for each rate period since the current rate schedule took effect[10] (including both summer and winter periods) and multiply those figures by the rates in the rate schedule (summer or winter, as applicable[11])

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[10] Byusing consumption data only since the current rate schedule took effect we can isolate the usage fluctuation due to past price changes from fluctuation due to true shifts in demand, therefore producing more accurate estimates. Concentrating on the most recent usage trend should also give us better estimates.

[11] Summeris the period May 1 through October 31, Winter is the period November 1 through April 30.

for the month under consideration. For example, Figure 2 shows the budget estimate worksheet for the main NPS electrical account for May 1994.[12] Adding the total of each account worksheet would give the total estimated monthly electricity cost.

Electrical Service	Average use/month since 7/93	Unit Price ($)	Total Estimated Cost ($)
Summer Peak-Period Energy (kWh)	298,616	.07044	21,035
Summer Partial-Peak Period Energy (kWh)	311,982	.05469	17,062
Summer Off-Peak Period Energy (kWh)	699,120	.05260	36,774
Peak-Period Power Demand (kW)	2,619	11.80	30,904
Partial-Peak Power Demand (kW)	2,605	2.65	6,903
Maximum Demand (kW)	2,619	2.55	6,678
Customer Charge	1	310.00	310
TOTALS			119,666

Figure 2 Budget Estimate Worksheet for May 1994

The actual charges can still be expected to vary from the estimate for the reasons outlined in Chapter I, but this revised estimating procedure should produce more accurate budget estimates.

Natural gas usage shows a distinct pattern with respect to summer and winter consumption although usage still varies from year to year for any given month. Figure 3 shows the consumption (in therms) for one PG&E account. Therefore, it

[12] PG&E instituted a temporary "Economic Stimulus Credit" of $0.004/kWh that expires on December 31, 1994. The estimate worksheet did not include this credit because of its temporary nature.

appears that the best estimating procedure for natural gas is to take the average monthly usage over the previous season (summer or winter) instead of over a previous fixed period of time and use those figures along with the appropriate rate schedule for the month under consideration.

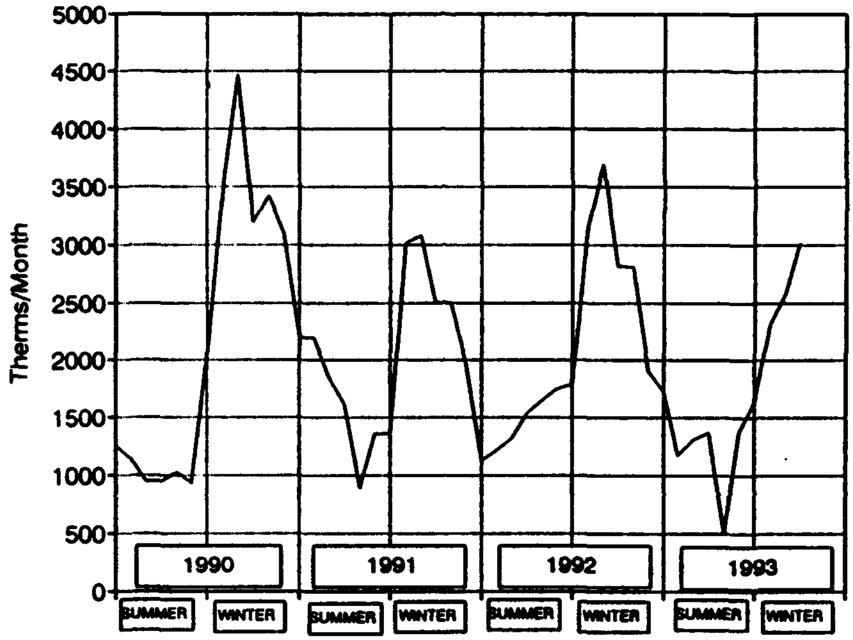

Figure 3 Typical Natural Gas Consumption

C. ALLOCATING INVOICE CHARGES AMONG USERS

This task is especially suited for accomplishment by a spreadsheet. Whichever cost allocation scheme is in use (fixed-charge, percentage of meter, etc.) can be easily reflected in the formulas assigned to each cell. Changing the allocation scheme could be accomplished simply by changing the cell formulas. For example,

Appendix 9 shows each account for the main station summary bill on the left and each user across the top. If fixed charges are used (as is the current practice), those charges are simply entered in the appropriate row. The amount NPS must pay is the account total less the sum of all other users' charges. If the cost allocation scheme were to change so that each user pays a percentage of the total metered charges, the cell formulas for each user would simply be changed to calculate the appropriate percentage of the total for that particular account. If some users were metered (this topic is discussed at length in the next chapter), the actual usage for both energy and peak power for each rate period would be "plugged in" to the current rate structure to determine the actual cost for that user. This amount would then be subtracted from the account total along with the amounts for all other users on the account to determine the NPS portion of the bill.

Note that the spreadsheet allows for multiple allocation schemes. For example, on the main electrical account there could be a combination of fixed-charge users, metered users and users paying a percentage of the total bill. The NPS portion, again, would be the total charges for the meter less the sum of all other users' charges. All the cost data required to prepare the invoice certification (NAVCOMPT 2035) is contained in this portion of the spreadsheet.

D. PREPARING PERIODIC REPORTS

The portion of the spreadsheet shown in Appendix 9 is repeated 11 times in the spreadsheet for a total of 12 worksheets, each representing one month's billing. The

totals for each user are copied to another part of the spreadsheet that summarizes the usage and dollar amounts to be reported in the following:

- Procurement Report of Utilities Services - Summary for Accounts Less than $25,000 Per Year.[13] (There are 39 such accounts at NPS for all utilities).
- Defense Energy Information System (DEIS) Report

Each of the above reports requires different utility consumption data in a unique format. A database containing the data by user, quantity consumed, type of utility, contract number, supplier, and account number would allow the required data to be extracted as necessary for the particular report.

A database (using Zenith Data Systems' ENABLE) containing some of the above data elements is currently used by the PW Fiscal Division primarily for accounting purposes. A revised database linked to the above spreadsheet would allow the preparation of reports for multiple purposes with minimal effort. Public Works has sufficient in-house computer expertise to incorporate the necessary data elements from the above spreadsheet into a revised database. The database PARADOX will be used instead of ENABLE because it is the standard Public Works database program and is produced by the same company that makes the QUATTRO PRO spreadsheet.

[13] The Summary for Accounts More Than $25,000 Per Year is prepared by Western Division, Naval Facilities Engineering Command (WESTDIV).

IV. MARKET PRICING OF ELECTRICITY

A. INTRODUCTION

Chapter I discussed the current method of allocating costs among nonmetered users by using engineering estimates of consumption and described the deadweight loss (DWL) that may result. This chapter examines the DWL issue in more depth for the existing and alternative electricity cost allocation schemes.[14]

The demand curve for electricity must be known in order to calculate the DWL. That is, we must know the quantity of electricity that would be consumed over a range of prices. From this curve we could then calculate the price elasticity of demand, e, which is simply a measure of the percentage change in the quantity demanded in response to a certain percentage change in price and is defined mathematically as

$$e = -\frac{\Delta Q/Q}{\Delta P/P} \qquad (1)$$

or

$$e = -\frac{\Delta Q}{\Delta P}\left(\frac{P}{Q}\right) \qquad (2)$$

Demand is said to be elastic when $e > 1$ and inelastic when $e < 1$.

[14]The reader is assumed to have a basic understanding of the economic concepts discussed here, including supply and demand curves and economic efficiency.

In this case, we do not have the empirical data with which to construct the demand curve. We know the quantity demanded at the current price and the quantities demanded at historical prices, but cannot isolate past changes in quantity demanded due solely to price changes from changes due to other factors such as adding new facilities, changing base operating tempo, etc. In other words, we have no way of distinguishing between past changes along the demand curve from past shifts in the demand curve.

To solve this problem, we will have to work backwards. By looking to previous studies of energy demand, it is possible to determine a reasonable value for price elasticity.[15] Using this elasticity it is possible to calculate other points on the demand curve. By using a range of elasticities, it is possible to construct "flat" and "steep" demand curves with corresponding high and low values for the DWL. By doing so, we can allow for uncertainty in the elasticity value when comparing the DWLs for each of several cost allocation schemes.

To calculate the DWL, we must also know, in addition to the demand curve, the marginal cost to the user for an additional unit of electricity This data is readily available because the marginal cost to the user is an explicit part of any cost allocation scheme. For example, in the case of users paying fixed monthly amounts, the marginal cost is zero. In the case of metered users, the marginal cost is equal to the market price.

[15] We are concerned with the long-run price elasticity of demand, not the short-run elasticity because we intend to make comparisons of the DWLs over a period of years.

Once the demand curves and marginal costs are known, high and low values of the DWLs (corresponding to the high and low values of the elasticities used) for the existing and alternative allocation schemes may be easily calculated. Then, to decide whether to implement a particular cost allocation method, it is necessary only to compare the resulting change in the DWL to the costs of executing the method, if any (e.g installing meters).

B. CONSTRUCTING THE DEMAND CURVES

Twelve of the thirteen users currently paying fixed charges for electricity are under the same PG&E account.[16] This account is on rate Schedule E-20. Having most of these users under the same rate schedule simplifies matters in one sense because we need only examine the historical usage data and construct demand curves for one meter instead of many. On the other hand, because of the complexity of Rate Schedule E-20 we must construct 10 different demand curves corresponding to the 10 different types of electrical service provided:[17]

- Summer peak-period energy charge[18]
- Summer partial-peak period energy charge

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[16] The twelve are Quarters A, Quarters C-N, COMO, BRDENTAL, DHRSC, DIS, DPS, DRMI, PSD, ROICC, TRADOC, and part of NEX. The only other fixed-charge user is the Golf Course, whose usage is small.

[17] The other component of Schedule E-20, the monthly customer charge, is fixed. Since this charge does not vary with the quantity of electricity consumed, it is not appropriate to include it in the demand curves. See Chapter I for a detailed discussion of the PG&E rate structures.

[18] Recall that Summer is the period May 1 through October 31, Winter is the period November 1 through April 30. There is no peak-period during the winter, only partial-peak and off-peak periods.

- Summer off-peak period energy charge
- Summer maximum peak-period demand[19] charge
- Summer maximum partial-peak period demand charge
- Summer maximum demand charge
- Winter partial-peak period energy charge
- Winter off-peak period energy charge
- Winter maximum partial peak-period demand charge
- Winter maximum demand charge

PG&E data was examined over the 7-month period from July 1993, when Schedule E-20 was last revised, to February 1994, the latest month for which data is available, to determine for both the summer and winter an average monthly power demand (for each type of demand) and an average daily energy usage for each rate period. The average daily energy figures were then multiplied by 30 to obtain the average monthly usage for the entire meter (See Appendix 3).

Analyzing the historical power demands revealed the following:

- The power demand averaged 2620 kW with very little variation across rate periods or even across seasons.
- The maximum demand (the highest demand occurring at any time during the month) always occurred during the peak rate period. In other words, the peak demand (the highest demand occurring during the peak rate period) and the maximum demand always occurred simultaneously.

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[19] Theword "demand" is used in two different senses in this chapter. It refers to the quantity demanded (in kWh) of a service (e.g. peak-period energy, partial-peak energy, etc.) and also to the peak power (in kW) demanded during a period on which PG&E bases its demand charge.

These observations allow us to combine the three summer power demand curves and the two winter power demand curves with one overall curve for each season. In other words, instead of having three summer power demand curves with prices per kW of $11.80, $2.65 and $2.55 and two winter power demand curves with prices of $2.65 and $2.55, we can substitute one summer demand curve with a price of $17.00/kW and one winter curve with a price of $5.20/kW. This allows us to reduce the number of demand curves we must construct from ten to seven. Later we will see that the DWL for the combined curve is exactly equal to the sum of the DWLs from separate curves.

Since the 12 fixed charge users represent about 10 percent of the total account usage, we may construct aggregate demand curves representing the total usage of these 12 users by multiplying by .10 the quantity demanded at each point on the overall demand curve for each type of electrical service provided through the meter. For example, the average monthly demand for summer peak-period energy is 298,616 kWh at a unit price of $.07044. The monthly demand for the 12 users as a group would then be 29,862 kWh (.10 times 298,616 kWh) at this price.[20] This point is the starting point for constructing the demand curves. Similarly, the 12 users may be considered to contribute to the power demands in the same proportion. That is, if the monthly power demand is 2620 kW, the 12 users are assumed to be responsible for 10 percent of that amount or 262 kW.

[20] Actually, the historical demand figures already reflect some DWL because of the 12 fixed-price users, however we will ignore this because the combined usage of the 12 is small relative to the total usage of the meter.

Reasonable estimates of the price elasticity of demand were obtained from the literature. Various formal models of energy demand have been used to estimate price elasticities, each with its own shortcomings. Perhaps the most significant shortcoming of the commercial electricity demand studies as a group is that they do not distinguish among the many diverse organizations that comprise the commercial sector (Bohi, 1981). Virtually all the studies, however, indicate that commercial electricity demand is elastic in the long-run with the elasticities obtained ranging from 1.00 (Webb and Ricketts, 1980) to 1.60 (Bohi, 1981). We will use a midrange value of 1.30 as the upper limit of e. Because of the inherent uncertainty of the elasticity value, we will duplicate our DWL calculations using an elasticity of 0.8 (indicating that the long-run demand is inelastic) to see if it makes a difference when comparing the DWLs to the costs of implementing a new allocation scheme.

With a known point on the demand curve and a value for e, the demand curve may be constructed. Note that Equation (2) may be rewritten as

$$e = -\frac{(Q_1 - Q)}{(P_1 - P)}\left(\frac{P}{Q}\right) \tag{3}$$

Solving for Q_1 gives

$$Q_1 = Q - \left(\frac{Q}{P}\right)(P_1 - P)(e) \tag{4}$$

Since we know e, Q and P, we can determine Q_1 for any P_1. For example, recall that the monthly demand for summer peak-period energy by the 12 fixed-price users is

29,862 kWh at $.07044/kWh. Substituting these values into Equation (4) and using $e = 1.30$ and $P_1 = 0$ gives[21]

$$
\begin{aligned}
Q_1 &= 29862 - \left(\frac{29862}{.07044}\right)(0 - .07044)(1.3) \\
&= 68{,}683\ kWh
\end{aligned}
\tag{5}
$$

We now have two points on the demand curve for summer peak period energy.[22] Repeating the above calculation for $e = 0.8$ gives $Q_1 = 53{,}752$ kWh. The resulting demand curves are shown in Figure 4. The remaining six curves were calculated in the same manner.

C. DEADWEIGHT LOSS OF USING FIXED MONTHLY CHARGES

The DWL for the 12 users paying fixed monthly charges for electricity is shown graphically in Figure 5 for summer peak-period energy with $e = 1.3$.

The DWL is the area under the demand curve bounded by a vertical line between the points (Q, P)[23] and (Q, P_1) where P_1 is the marginal unit cost to the user and by a horizontal line between the aforementioned vertical line and the demand curve at point (Q_1, P_1). The DWL can be calculated using the formula for

---

[21] Although any value of P_1 may be used to obtain a second point on the demand curve, by setting P_1 equal to the marginal cost we simplify the DWL calculations later on.

[22] The value of e actually differs at each point along the demand curve but our value is sufficiently accurate over the range of demand under consideration.

[23] Recall that the point (Q, P) is derived from recent consumption data and is the same for both demand curves ($e = 1.3$ and $e = 0.8$).

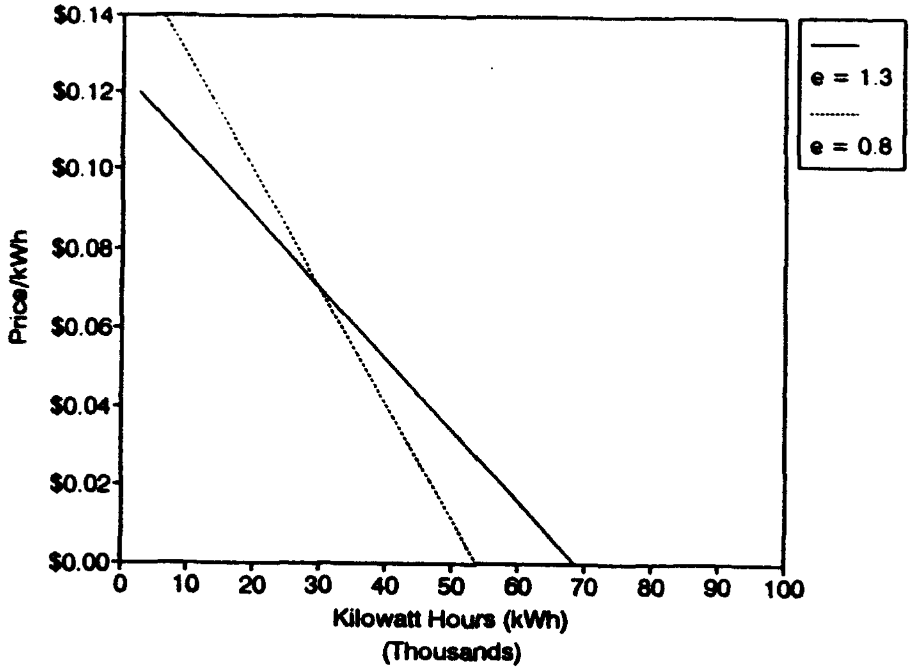

Figure 4 Summer Peak-Period Energy Demand

the area of a right triangle:

$$DWL = \frac{1}{2}(Q_1 - Q)(P_1 - P) \tag{6}$$

In the instant case, the DWL[24] is

$$\begin{aligned} DWL &= \frac{1}{2}(68683 - 29862)(0 - .07044) \\ &= \$1,374 \end{aligned} \tag{7}$$

We can also compute the DWL directly by substituting Equation (4) into Equation (6) to get

[24] Equation(7) yields a negative number, but we drop the minus sign because we are describing the result as a "loss". Also, there may be slight differences due to rounding.

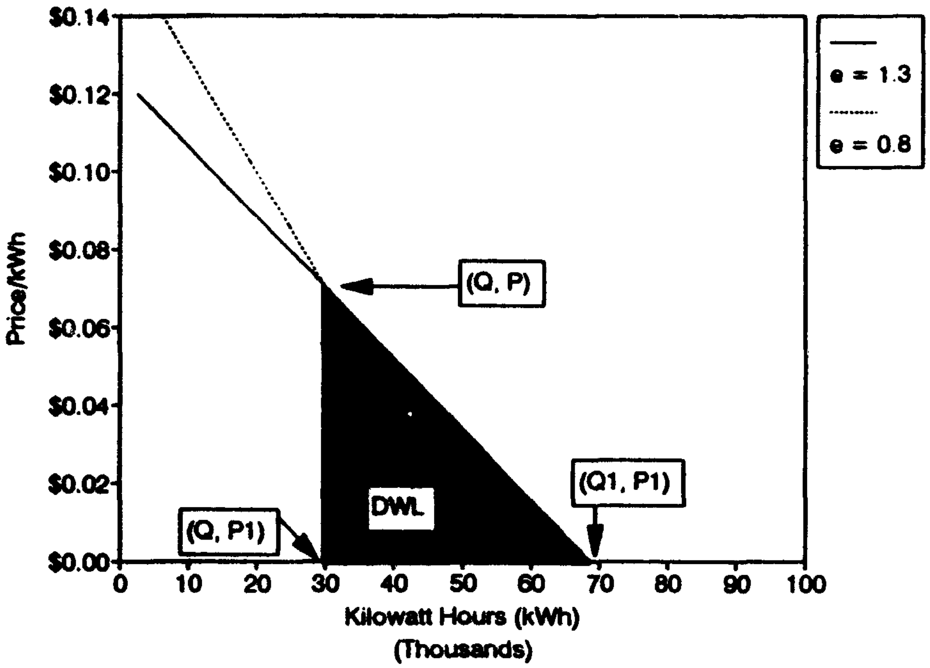

Figure 5 Existing DWL for e = 1.3

$$DWL = -\frac{1}{2}(P_1 - P)^2(\frac{Q}{P})(e)$$

$$= -\frac{1}{2}(0 - .07044)^2(\frac{29862}{.07044})(1.3) \qquad (8)$$

$$= \$1{,}374$$

Repeating the above calculation for e = 0.8 gives a DWL of $841. This result agrees with our expectation that the more inelastic or "steep" the demand curve is, the lower the DWL. This is shown graphically in Figure 6 for summer peak-period energy.

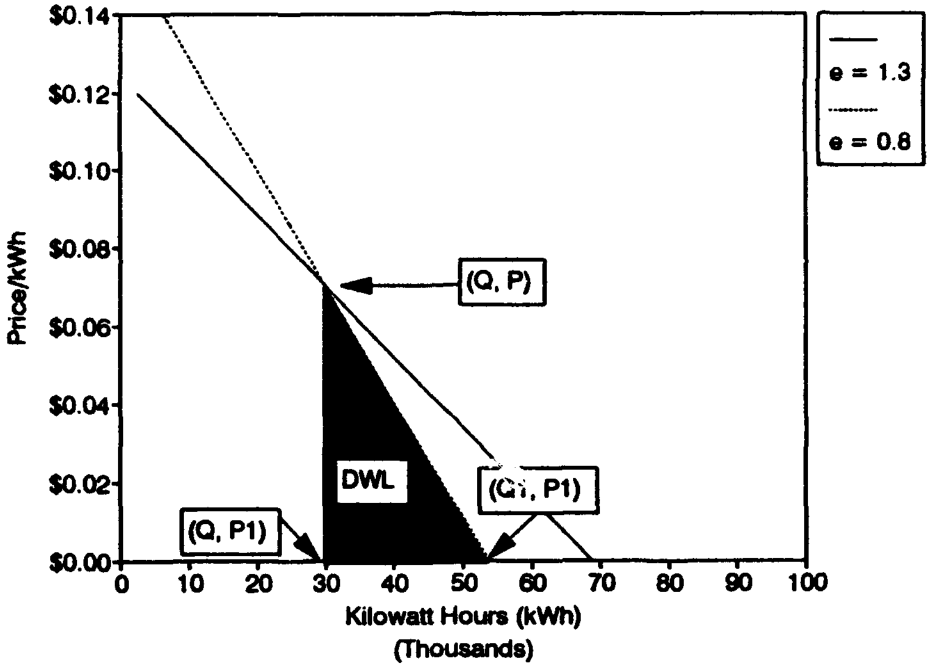

Figure 6 Existing DWL for e = 0.8

The DWL calculations were repeated for each curve. Appendix 4 summarizes the calculations for both values of *e*.

Now that we have a way of calculating the DWL we can show that our method of using one curve each to represent summer and winter power demands is valid. Using Equation (6) to calculate the DWL for the combined summer power demand curve gives

$$DWL = \frac{1}{2}(603 - 262)(0 - 17.00) \qquad (9)$$

$$= \$2{,}895$$

Calculating separately the DWLs for peak-period demand, partial-peak period demand and maximum demand gives, respectively,

$$DWL_1 = \frac{1}{2}(603 - 262)(0 - 11.80) = \$2{,}010$$

$$DWL_2 = \frac{1}{2}(603 - 262)(0 - 2.65) = \$451 \qquad (10)$$

$$DWL_3 = \frac{1}{2}(603 - 262)(0 - 2.55) = \$434$$

or

$$DWL = \frac{1}{2}(603 - 262)(-11.80 - 2.65 - 2.55)$$

$$= \frac{1}{2}(603 - 262)(-17.00) \qquad (11)$$

$$= \$2{,}895$$

Therefore, combining the power demand curves into one curve yields the exact same result when calculating the DWL.

D. DEADWEIGHT LOSS OF ALTERNATIVE ALLOCATION METHODS

The DWL calculations were repeated for two alternative methods:

- Charging the 12 users a fixed percentage of the meter serving them instead of a fixed dollar amount.

- Installing meters capable of recording time-of-use and peak demand during each rate period.

Recall that the 12 users as a group currently consume approximately 10 percent of the total usage recorded by their meter. Rather than charging fixed dollar amounts, these 12 users could collectively be charged 10 percent of the total usage.[25] Their costs would then rise or fall along with the total usage recorded by the meter. Intuitively, we expect this method to reduce the DWL because the marginal cost to the user is no longer zero. The marginal cost P_1 would be

$$P_1 = .10(P) \tag{12}$$

because the 12 users would pay ten percent of the cost of each additional unit of electricity consumed. From Equation (8), the DWL is then

$$DWL = -\frac{1}{2}(.10P - P)^2(\frac{Q}{P})(e) \tag{13}$$

Using our earlier example with $e = 1.3$, the DWL is

[25] The 10 percent would in turn be allocated among the 12 users (e.g. DRMI 2%, DIS .8%, etc.)

$$
\begin{aligned}
DWL &= -\frac{1}{2}(-.90P)^2(\frac{Q}{P})(e) \\
&= -\frac{1}{2}[(-.90)(.07044)]^2(\frac{29862}{.07044})(1.3) \\
&= \$1,107
\end{aligned}
\tag{14}
$$

The DWL is indeed reduced, from $1,374 to $1,107, with this allocation method. Graphically, the DWL is shown in Figure 7 for summer peak-period energy. Note that the demand curves do not change but only the area of the DWL. The calculations for the other six demand curves are summarized in Appendix 5 for both values of *e*.

The total annual DWL is reduced from $80,940 to $65,556 (for $e = 1.3$) and from $49,812 to $40,344 (for $e = 0.8$) with this allocation method with virtually no implementation costs.

The other method under consideration is the installation of meters. With this alternative, the DWLs would be reduced to zero because the 12 users would pay all costs for the exact amount of electrical services consumed. However, this method has substantial implementation costs which are summarized in Appendix 6.[26] The implementation costs shown include one-time costs for installation labor and materials and the monthly meter reading cost. The cost estimates are based on in-house procurement, installation and reading of the new meters because, if PG&E

[26] Thecost estimates in Appendix 6 were prepared by the NPS Public Works Department, Maintenance Control Division, Planning and Estimating Section.

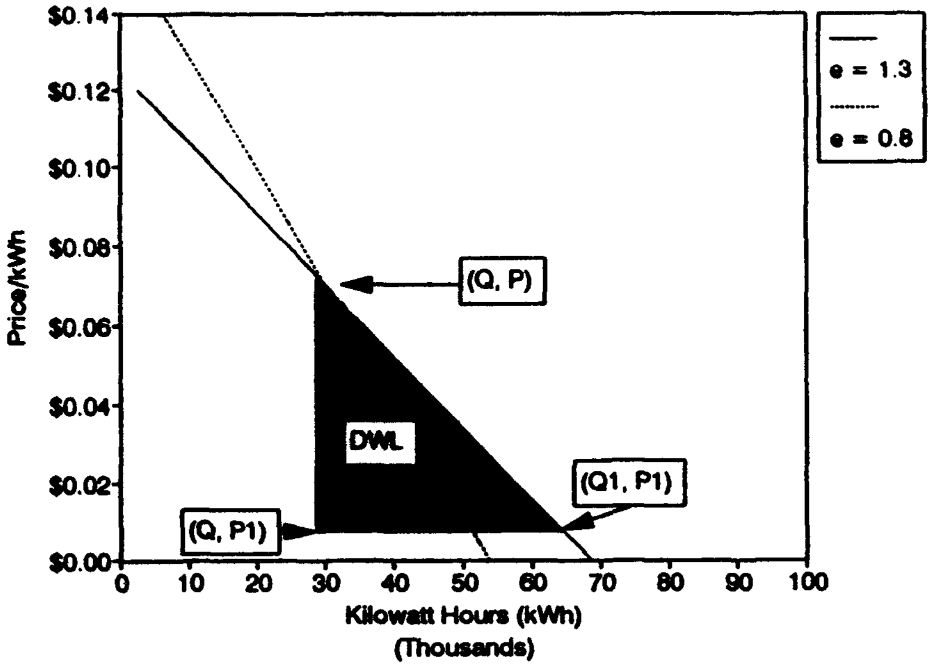

Figure 7 DWL for Alternative #1 (e = 1.3)

were to execute the submetering, the submeters would not remain on Schedule E-20 but would be assigned a different schedule based on their lower individual consumption. The implementation costs would increase substantially because the other rate schedules do not include the volume discounts present with E-20 (recall that PG&E customers must have a maximum monthly demand of <u>at least</u> 1,000 kW to qualify for Schedule E-20.)

Appendix 7 summarizes the implementation costs and changes in DWL for the two alternative allocation methods discussed above versus the existing method. Although the useful life of the submeters is at least 15 years, all cost flows were discounted over only five years because of the potential for changing tenant locations,

price changes or shifts in the demand curve that could decrease the DWL. A shorter discount period is more conservative because the large initial implementation costs are still recognized while the estimated savings are lower. A discount factor of 10% was used in accordance with SECNAVINST 7000.14A, "Economic Analysis and Program Evaluation for Resource Management".

Appendix 7 demonstrates that net cost savings of $230,993 (for e = 1.3) or $108,448 (for e = 0.8) may be realized by individually metering the 12 fixed-charge users and net savings of $60,564 (for e = 1.3) or $32,273 (for e = 0.8) may be realized by simply charging the 12 users a fixed percentage of the total consumption instead of a fixed dollar amount.

Although both alternatives result in net cost savings even for the inelastic demand assumption of $e = 0.8$, it would be useful to know the value of e that would result in a net savings of zero (i.e. the reduction in the DWL would be equal to the implementation cost). Since the percent-of-meter method (Alternative #1) always reduces the DWL with no implementation costs, a net savings would result for every value of e.[27] For the individual-metering method, however, the change in DWL becomes smaller as the value of e gets smaller. For $e = 0.35$, the installation of meters would result in a DWL reduction of $85,792, which approximates the implementation cost of $87,653. Therefore, installing meters would result in net cost savings as long as $e > 0.35$.

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[27] Except, of course, for the perfectly inelastic (vertical) demand curve where $e = 0$.

V. REVISED COST ACCOUNTING AND INVOICING PROCEDURES

A. INTRODUCTION

Let us briefly review where we stand at this point. Chapter I discussed the overall data environment and shed light on the reasons why cost accounting for utilities is somewhat complicated. Chapter II outlined the existing cost accounting and invoice processing procedures, while Chapter III explored spreadsheet and database tools that can be employed to help manage the data. Chapter IV discussed in detail the deadweight loss resulting from the existing cost allocation method.

Armed with this knowledge, we are now in a position to synthesize it and produce revised cost accounting and invoice processing procedures.

The issue of transferring certain utility cost accounting functions from Public Works to the Comptroller was raised in Chapter II. An analysis of the existing procedures indicate that Public Works is best suited to perform the following:

- Determine the cost allocation method and revise it when necessary to reflect changes due to users' location, size, equipment additions, etc.
- Prepare the Procurement Report of Utilities Services and DEIS reports
- Consult with the Western Division, Naval Facilities Engineering Command (WESTDIV) as necessary on all utility technical and contractual issues[28]
- Act as the command's primary point of contact with utility suppliers

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[28] WESTDIV is the Engineering Field Division serving NPS and has Contracting Officer responsibility for all NPS utility contracts.

The Comptroller Department should:

- Prepare annual and monthly cost estimates
- Allocate costs upon receipt of the invoice and prepare invoice certifications
- Request funds from users
- Track user funds vs. actual costs and request additional funds if necessary
- Manage accounting data associated with utility costs
- Advise Public Works on questions concerning reimbursability (i.e. which users must pay for utilities in accordance with the Navy Comptroller manual)

The above division of responsibility allows each department to do what it does best and reduces the back-and-forth exchange of data between the Comptroller and Public Works departments. The result should be faster, more accurate invoice processing. The utilities accounting technician billet would be transferred from Public Works to the Comptroller in order to effect this transfer of responsibility.

B. REVISED PROCEDURES

The specific steps required to account for utilities costs and process invoices are essentially the same as discussed in Chapter II. The "overhauling" of the process was actually performed within each step by improving the way the function is performed (e.g. using a different cost allocation method to reduce the deadweight loss) or by reassigning responsibility for performing the function (e.g. having the Comptroller request and track user funds instead of Public Works).

A review of current ISAs and Command Evaluation reports indicate that all utility users are reimbursing NPS appropriately[29] with the exception of the Scheduled Airlines Ticket Office (SATO). Therefore, the first change to the existing procedures would be to include SATO as a reimbursable user and establish a reimbursement rate.

Another change involving the invoice certification would help speed up invoice processing. Rather than paying the invoice with each users' line of accounting data listed on the certification, it is possible to certify the invoice using only one line of NPS accounting data and then execute a "cost transfer" whereby the individual users reimburse NPS for their share. Using this cost transfer method would prevent the entire invoice from being delayed because one or two users do not have sufficient funds on hand to cover their portion of the bill, as discussed in Chapter II. The invoice would be sent to the AAA without delay and any funding problems could be worked out immediately afterwards.[30]

The revised procedures are shown in Appendix 11 and summarized as follows:

1. The Comptroller prepares estimates of annual cost for each utility for each user. The Comptroller also estimates utility costs for the upcoming month and records obligations at the beginning of the month in the STARS FL system. The estimates are prepared using the techniques described in Chapter III.

2. The Comptroller notifies users of the annual cost estimates and tracks receipt of funds vs. actual costs.

---

[29] Utilities for certain users are on a nonreimbursable basis as authorized by the Navy Comptroller manual.

[30] The Comptroller Dept. is to be credited for this idea.

3. The Comptroller assigns and tracks all accounting data associated with utility costs (JONs, serial numbers, etc.).

4. When an invoice is received, the Comptroller examines it for any irregularities and establishes the date by which payment must be made based on the terms of the contract or the Prompt Payment Act if applicable. Public Works assists with the resolution of any technical issues pertaining to the invoice.

5. PW performs the technical certification of the invoice. The Comptroller prepares the cost certification using only one line of accounting data and sends the certification to the AAA.

6. The Comptroller allocates costs to the individual users using the spreadsheet developed in Chapter III, which reflects the current cost allocation method from the alternatives presented in Chapter IV. Cost transfers are executed to reimburse NPS and the Comptroller adjusts the obligations to reflect the actual costs.

The above procedures are applicable to each type of utility invoice.

VI. SUMMARY AND RECOMMENDATIONS

A. SUMMARY

This thesis examined the existing utility cost accounting and invoice processing procedures at NPS. A number of general factors, as well as factors specific to each utility, were identified that complicate those procedures. The factors identified helped shape the development of spreadsheet and database tools to automate the cost accounting process and influenced the design of revised invoice processing procedures.

The existing cost allocation method was extensively analyzed as were several alternatives. The data demonstrate that the deadweight loss from charging certain users fixed dollar amounts per month for electricity may be reduced significantly by charging the users a percentage of the total charges of the meter by which they are served, at virtually no cost. Furthermore, the deadweight loss may be eliminated entirely by charging users the market price, requiring the installation of individual Navy-owned time-of-use meters capable of recording peak demand during each rate period. Despite the implementation costs of this method, the net savings are greater than with the percentage-of-meter method described above.

B. RECOMMENDATIONS

The following actions are recommended:

- Immediately implement the percentage-of-meter method of allocating utility costs. As stated in Chapter IV, doing so will sharply reduce the deadweight loss with no implementation costs.

- Reassign certain functions from Public Works to the Comptroller as discussed in Chapter V to allow each department to do what it does best.

- Implement the spreadsheet and database tools developed in Chapter III.

- Consolidate the numerous PG&E contracts under one contract number to reduce reporting requirements and thereby simplify the database currently required to track the data by contract.

- Conduct joint training with representatives from WESTDIV, Public Works and Comptroller Departments to finalize the revised invoice processing procedures and improve coordination and communication.

- Document, for each user, the method used to calculate charges for each utility. The documentation should include the building(s)/spaces occupied by the user, the number of the meter serving those building(s)/spaces and its associated vendor account number, and calculations of the utility charges based on the allocation method in use (if the user is not individually metered).

- Require the Public Works Engineering Division to notify the Fiscal Division of any project or work that requires a change to the cost allocation scheme. Direct the Public Works Maintenance Control Division to route a copy of any Work Request that has the potential to affect utility consumption by any user to the Engineering Director.

- Request that WESTDIV examine NPS natural gas consumption and cost data under the NGC contract and the PG&E transport charges to determine if it is advantageous to continue to purchase gas from NGC instead of PG&E.

APPENDICES

APPENDIX 1
REQUIRED INVOICE PROCESSING TIMES

Invoice	Vendor	Time Allowed[31]	Req'd By[32]	# lines Acct. data
Gas/Elec-1	PG&E	15 days	Contract	2
Gas/Elec-2	PG&E	15 days	Contract	5
Gas/Elec-3	PG&E	15 days	Contract	5
Gas/Elec-4	PG&E	15 days	Contract	26
Gas	NGC	30 days	PPA	13
Water-1	CAL-AM	22 days	Contract	1
Water-2	CAL-AM	22 days	Contract	2
Water-3	CAL-AM	22 days	Contract	1
Water-4	CAL-AM	22 days	Contract	3
Water-5	CAL-AM	22 days	Contract	14
Sewage-1	City of Monterey	30 days	PPA	1
Sewage-2	MRWPCA	20 days[33]	Contract	2

[31] Timestated is from date of receipt of a proper invoice, unless otherwise noted.

[32] PPA is the Prompt Payment Act

[33] Timestated is from date of invoice, regardless of when received by NPS.

Sewage-3	MRWPCA	20 days[30]	Contract	1
Refuse-1	City of Monterey	30 days	Contract	5
Refuse-2	City of Monterey	30 days	Contract	2
Cable TV-1	MPTV	30 days	PPA	1
Cable TV-2	MPTV	30 days	PPA	1
Cable TV-3	MPTV	30 days	PPA	1

APPENDIX 2

UTILITY USERS

		Elec	Gas	Water	Sewage	Refuse
NPS O&M,N-FUNDED USERS						
All depts. except FHN&MC and NAF-funded users below		X	X	X	X	X
NPS FHN&MC-FUNDED USERS						
LMV	La Mesa Village (Officer Housing area)	X	X	X	X	X
QTRS A	Quarters A (Superintendent's Quarters)	X	X	X		X
QTRS C-N	Senior Officers' Quarters	X	X	X		
NPS NAF-FUNDED USERS						
GC	Golf Course	X	X	X		
COMO	Commissioned Officers Mess, Open	X	X	X		
TENANTS/OTHERS						
BRDENTAL	Branch Dental Clinic	X	X	X		
DHRSC	Defense Health Resources Study Center	X	X	X		
DIS	Defense Investigative Service	X	X	X		
DMDC	Defense Manpower Data Center	X				
DPS	Defense Printing Service	X	X	X		X
DRMI	Defense Resources Management Institute	X	X	X		
FAA	Federal Aviation Administration	X				
FNOC	Fleet Numerical Meteorology & Oceanography Ctr.	X	X	X	X	X
NEX	Navy Exchange	X	X	X		X
NRL	Naval Research Laboratory	X	X	X		X
PERSEREC	Personnel Security Research Center	X				
PSD	Personnel Support Detachment	X	X	X		
ROICC	Resident Officer in Charge of Construction	X	X	X		
TRADOC	Training and Doctrine Analysis Command (Army)	X	X	X		

APPENDIX 3

SUMMER ELECTRICITY DEMAND							
Period	# Days	Peak Energy	Partial-Peak Energy	Off-Peak Energy	Peak Demand	Partial-Peak Demand	Max De-mand
7/20/93-8/19/93	30	312,612	323,076	672,312	2642	2635	2642
8/19/93-9/20/93	32	298,915	315,677	782,208	2659	2649	2659
9/20/93-10/19/93	29	285,936	303,341	653,923	2556	2553	2556
10/19/93-10/31/93	12	127,786	129,038	291,902	2620	2584	2620
TOTALS	103	1,025,249	1,071,132	2,400,345	-	-	-
AVERAGE/ DAY FOR METER	-	9,954	10,399	23,304	-	-	-
AVERAGE/ MONTH FOR METER	-	298,616	311,982	699,120	2619	2605	2619
AVERAGE/ MONTH FOR TENANTS	-	29,862	31,198	69,912	262	261	262

WINTER ELECTRICITY DEMAND							
Period	# Days	Peak Energy	Partial-Peak Energy	Off-Peak Energy	Peak Demand	Partial-Peak Demand	Max De-mand
11/1/93-11/17/93	17	-	325,728	378,346	-	2596	2596
11/17/93-12/20/93	33	-	629,770	788,630	-	2570	2570
12/20/93-1/19/94	30	-	582,451	646,349	-	2582	2582
1/19/94-2/17/94	29	-	613,166	680,434	-	2733	2733
TOTALS	109	-	2,151,115	2,493,759	-	-	-
AVERAGE/ DAY FOR METER	-	-	19,735	22,879	-	-	-
AVERAGE/ MONTH FOR METER	-	-	592,050	686,356	-	2620	2620
AVERAGE/ MONTH FOR TENANTS	-	-	59,205	68,636	-	262	262

APPENDIX 4

EXISTING ALLOCATION METHOD - DEADWEIGHT LOSS $e = 1.3$					
Period	**P ($)**	**Q**	**P_1 ($)**	**Q_1**	**DWL/ month**
Summer Peak-Period Energy (kWh)	.07044	29,862	0.00	68,683	$ 1,367
Summer Partial-Peak Period Energy (kWh)	.05469	31,198	0.00	71,755	$ 1,109
Summer Off-Peak Period Energy (kWh)	.05260	69,912	0.00	160,780	$ 2,390
Summer Demand (kW)	17.00000	262	0.00	603	$ 2,895
Monthly Summer Deadweight Loss					$ 7,761
Total Summer Deadweight Loss (Monthly DWL x 6)					$46,566
Winter Partial-Peak Period Energy (kWh)	.06380	59,205	0.00	136,172	$ 2,455
Winter Off-Peak Period Energy (kWh)	.05353	68,636	0.00	157,683	$ 2,388
Winter Demand (kW)	5.20000	262	0.00	603	$ 886
Monthly Winter Deadweight Loss					$ 5,729
Total Winter Deadweight Loss (Monthly DWL x 6)					$34,374
TOTAL ANNUAL DEADWEIGHT LOSS					$80,940
PRESENT VALUE @10% OVER 5 YEARS					$(318,646)

EXISTING ALLOCATION METHOD - DEADWEIGHT LOSS e = 0.8					
Period	**P ($)**	**Q**	**P_1 ($)**	**Q_1**	**DWL/ month**
Summer Peak-Period Energy (kWh)	.07044	29,862	0.00	53,752	$ 841
Summer Partial-Peak Period Energy (kWh)	.05469	31,198	0.00	56,156	$ 682
Summer Off-Peak Period Energy (kWh)	.05260	69,912	0.00	125,842	$ 1,471
Summer Demand (kW)	17.00000	262	0.00	472	$ 1,782
Monthly Summer Deadweight Loss					$ 4,776
Total Summer Deadweight Loss (Monthly DWL x 6)					$28,656
Winter Partial-Peak Period Energy (kWh)	.06380	59,205	0.00	106,569	$ 1,511
Winter Off-Peak Period Energy (kWh)	.05353	68,636	0.00	123,545	$ 1,470
Winter Demand (kW)	5.20000	262	0.00	472	$ 545
Monthly Winter Deadweight Loss					$ 3,526
Total Winter Deadweight Loss (Monthly DWL x 6)					$21,156
TOTAL ANNUAL DEADWEIGHT LOSS					$49,812
PRESENT VALUE @10% OVER 5 YEARS					$(196,101)

APPENDIX 5

ALTERNATIVE ALLOCATION METHOD #1 - DEADWEIGHT LOSS $e = 1.3$					
Period	**P ($)**	**Q**	**P_1 ($)**	**Q_1**	**DWL/ month**
Summer Peak-Period Energy (kWh)	.07044	29,862	.007044	64,801	$ 1,107
Summer Partial-Peak Period Energy (kWh)	.05469	31,198	.005469	67,700	$ 898
Summer Off-Peak Period Energy (kWh)	.05260	69,912	.005260	151,709	$ 1,936
Summer Demand (kW)	17.00000	262	1.700000	569	$ 2,345
Monthly Summer Deadweight Loss					$ 6,286
Total Summer Deadweight Loss (Monthly DWL x 6)					$37,716
Winter Partial-Peak Period Energy (kWh)	.06380	59,205	.006380	128,475	$ 1,989
Winter Off-Peak Period Energy (kWh)	.05353	68,636	.005353	148,940	$ 1,934
Winter Demand (kW)	5.20000	262	.520000	569	$ 717
Monthly Winter Deadweight Loss					$ 4,640
Total Winter Deadweight Loss (Monthly DWL x 6)					$27,840
TOTAL ANNUAL DEADWEIGHT LOSS					$65,556
PRESENT VALUE @10% OVER 5 YEARS					$(258,082)

ALTERNATIVE ALLOCATION METHOD #1 - DEADWEIGHT LOSS $e = 0.8$					
Period	**P ($)**	**Q**	**P_1 ($)**	**Q_1**	**DWL/ month**
Summer Peak-Period Energy (kWh)	.07044	29,862	.007044	51,363	$ 682
Summer Partial-Peak Period Energy (kWh)	.05469	31,198	.005469	53,661	$ 553
Summer Off-Peak Period Energy (kWh)	.05260	69,912	.005260	120,249	$ 1,191
Summer Demand (kW)	17.00000	262	1.700000	451	$ 1,443
Monthly Summer Deadweight Loss					$ 3,869
Total Summer Deadweight Loss (Monthly DWL x 6)					$23,214
Winter Partial-Peak Period Energy (kWh)	.06380	59,205	.006380	101,833	$ 1,224
Winter Off-Peak Period Energy (kWh)	.05353	68,636	.005353	118,054	$ 1,190
Winter Demand (kW)	5.20000	262	.520000	451	$ 441
Monthly Winter Deadweight Loss					$ 2,855
Total Winter Deadweight Loss (Monthly DWL x 6)					$17,130
TOTAL ANNUAL DEADWEIGHT LOSS					$40,344
PRESENT VALUE @10% OVER 5 YEARS					$(158,828)

APPENDIX 6

	TENANT	ONE-TIME INSTALLATION COSTS		
		LABOR	MATERIAL	TOTAL
1	QTRS A	$ 2,000[34]	$ 2,000	$ 4,000
2	QTRS C-N			
3	COMO	$13,000	$20,000	$33,000
4	BRDENTAL	$ 3,000	$ 4,500	$ 7,500
5	DHRSC	0[35]	$ 1,000	$ 1,000
6	DIS	$ 1,000	$ 1,500	$ 2,500
7	DPS	$ 2,000	$ 3,000	$ 5,000
8	DRMI	0[36]	$ 1,000	$ 1,000
9	PSD	$ 2,000	$ 3,000	$ 5,000
10	ROICC	$ 7,000[37]	$ 7,800	$14,800
11	TRADOC			
12	NEX	$ 4,000	$ 7,500	$11,500
TOTALS		$34,000	$51,300	$85,300
MONTHLY METER READING (2 HRS/MO. x $25/HR)				$ 50

[34] The cost figures shown cover Qtrs. A and Qtrs. C-N.

[35] There is an unrelated electrical upgrade project planned for Root Hall. Therefore, the only additional cost would be for installation of the submeter.

[36] There is an unrelated electrical upgrade project planned for the west wing of Herrmann Hall. Therefore, the only additional cost would be for installation of the submeter.

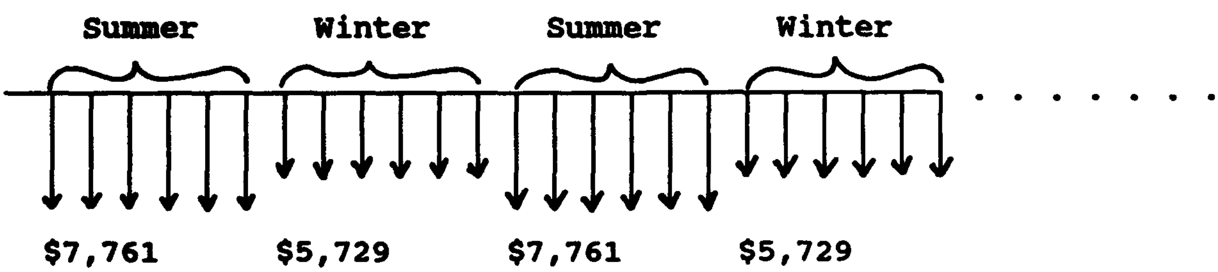
[37] The cost figures shown cover ROICC and TRADOC because they occupy the same building.

APPENDIX 7

Allocation Method	Deadweight Loss ($)			Install-ation cost	Net Savings[1] over Existing Method ($)	
	Monthly (except PVs)	e = 1.3	e = 0.8		e = 1.3	e = 0.8
Fixed-charge	Summer	7,761	4,776	-	-	-
	Winter	5,729	3,526		-	-
	PV[2]	(318,646)	(196,101)	-	-	-
Percent of meter	Summer	6,286	3,869	0	1,475	907
	Winter	4,640	2,855		1,089	671
	PV[2]	(258,082)	(158,828)	0	60,564	37,273
Individually Metered	PV[3]	0	0	(87,653)	230,993	108,448

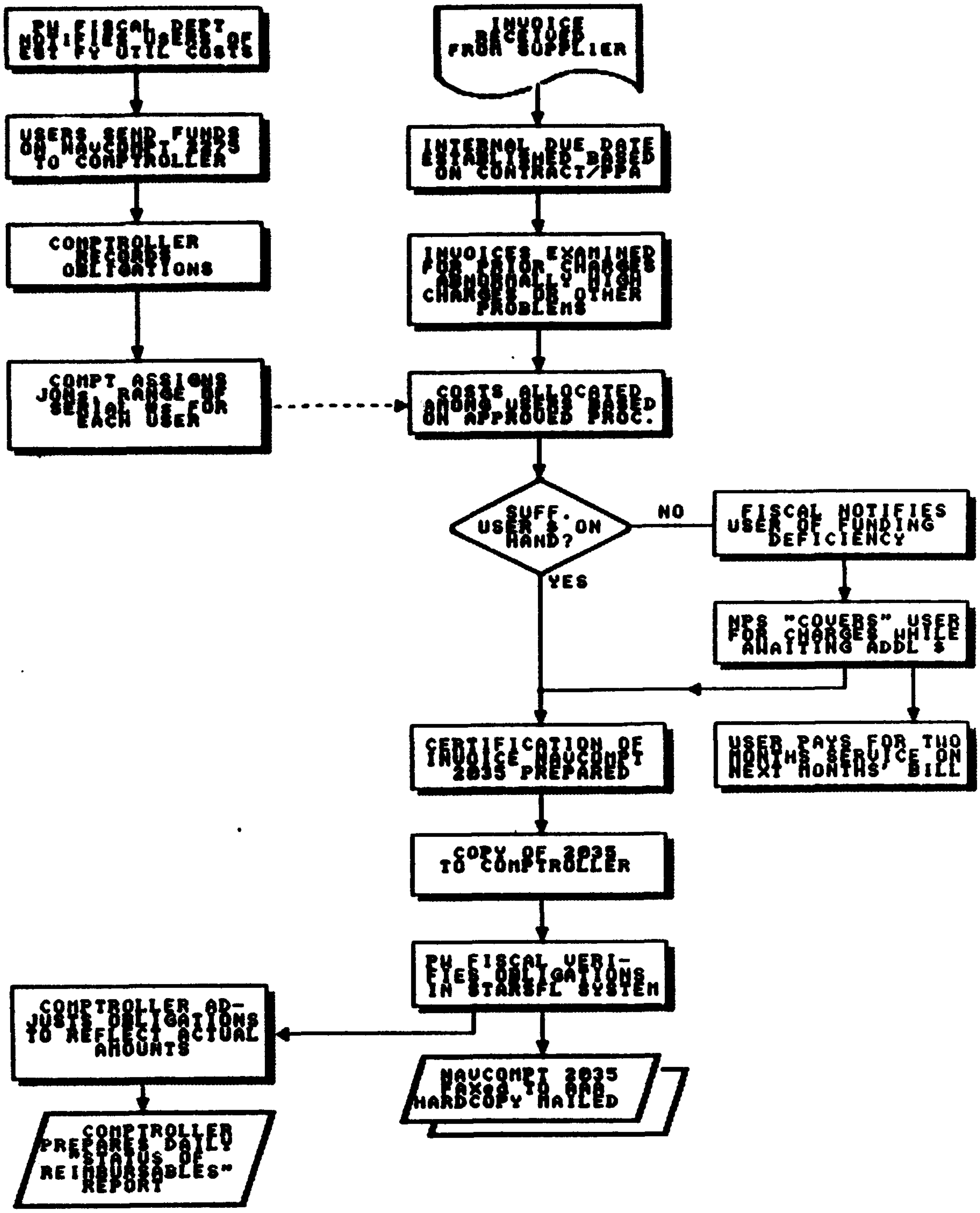
[1]Net Savings is equal to the change in DWL less any implementation costs

[2]PV was calculated using monthly cash flows for winter and summer over 5 years @10%. For example, the PV of the DWL for the fixed-charge allocation method for e = 1.3 may be shown graphically as:



[3]PV includes one-time meter installation costs and monthly meter reading cost over 5 years @10%

APPENDIX 8


EST FY UTIL COSTS
USERS SEND FUNDS
TO COMPTROLLER
COMPTROLLER
OBLIGATIONS
COMPT ASSIGNS
EACH USER
INVOICE
FROM SUPPLIER
INTERNAL DUE DATE
ON CONTRACT/PPA
INVOICES EXAMINED
PROBLEMS
COSTS ALLOCATED
ON APPROVED PROC.
SUFF.
USER $ ON
HAND?
NO
YES
FISCAL NOTIFIES
DEFICIENCY
NPS "COVERS" USER
AWAITING ADDL $
USER PAYS FOR TWO
NEXT MONTHS' BILL
CERTIFICATION OF
2035 PREPARED
COPY OF 2035
TO COMPTROLLER
PW FISCAL VERI-
IN STARSFL SYSTEM
COMPTROLLER AD-
AMOUNTS
NAVCOMPT 2035
HARDCOPY MAILED
COMPTROLLER
REPORT

APPENDIX 9

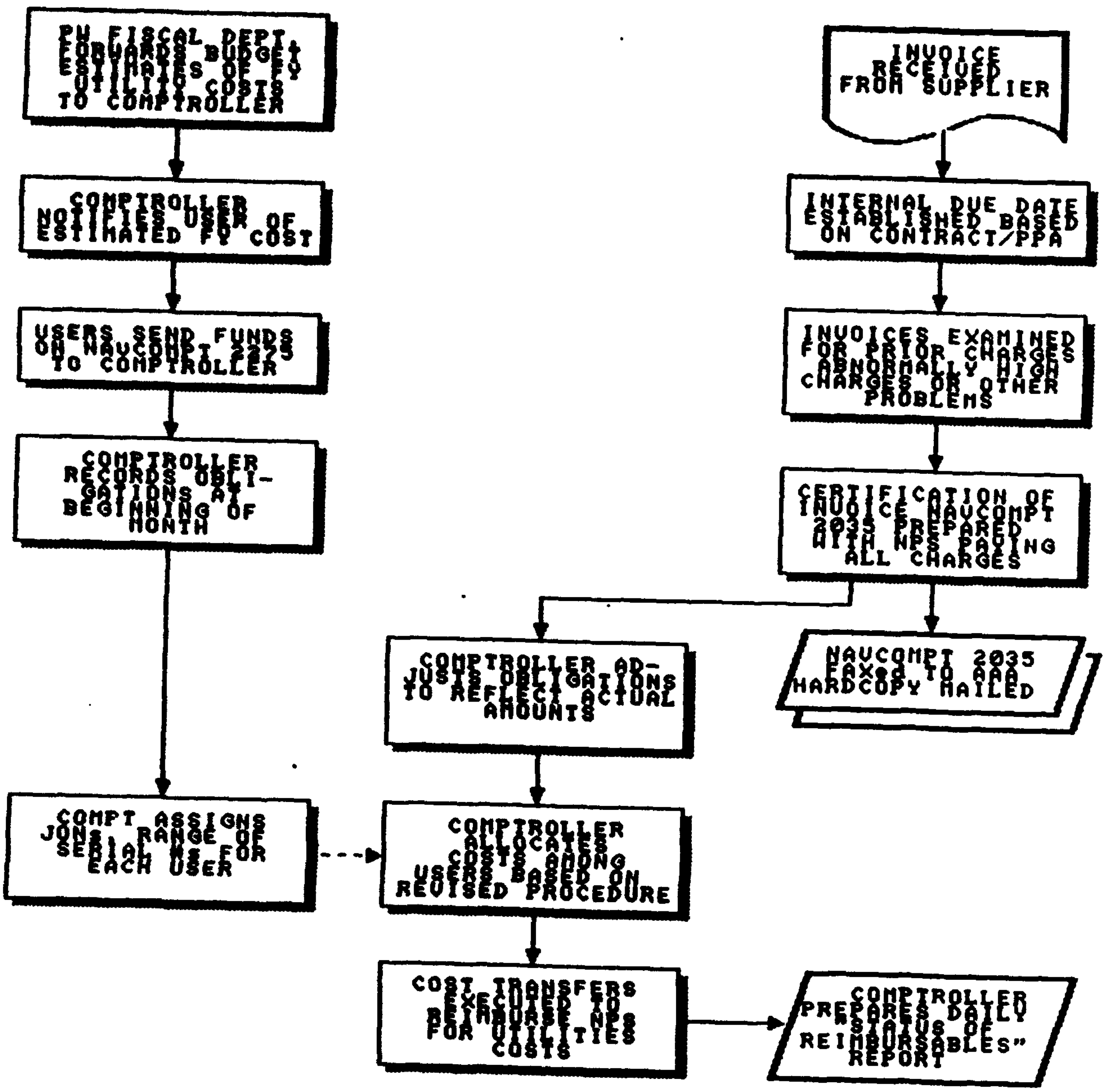
Account #	Service	Descrip.	TOTAL	Qtrs A	Qtrs C-N	COMO	BRDENTAL	DHRSC	DIS	PRINT	DRMI	PSD	RDICC	TRADOC	HEX	SC	FAA	Conf	NPS
VBM0001S01	ELEC	Ball Field	1124.25																1124.25
VBM0000111	ELEC	FAA	0.00														0.00		0.00
VBM[illegible]	ELEC	HEX Gas Stn	0.00												0.00				0.00
VBM0002101	ELEC	Trans & Sew	689.62																689.62
VBMT300701	ELEC	Main Stn	84857.08	57.74	2273.70	3888.88	391.78	178.20	88.80	168.80	2443.80	372.91	233.34	174.87	2841.70		0.00	8848.80	60132.70
VBMT300801	ELEC	Astro Lab	8468.30													468.00			7087.03
PST3000001	ELEC	Doppler Rad	342.30																342.30
VBM[illegible]	ELEC	Salt Wtr Lab	166.86																166.86
VBM[illegible]71	ELEC	Supply Whse	281.62																281.62
VBM[illegible]	ELEC	Shops	281.30																281.30
VBM[illegible]	GAS	Astro Lab	2768.60													224.00			2468.10
VBM[illegible]	GAS	PW Complex	3112.69																3112.65
VBM[illegible]	GAS	Shop	65.30																65.30
VBM[illegible]41	GAS	Bldg 814	21.67																21.67
VBM[illegible]	GAS	Bldg 340	632.12																632.12
CBMN100001	GAS	ME Lab	1032.04																1032.04
CBMN102101	GAS	Qtrs B	130.01																130.01
PBMA200131	GAS	Transport	13808.83	73.87	307.75		82.80	37.27	58.80	28.30	2134.28	175.86	48.75	58.85					6557.44
			116841.16	130.01	2701.45	3888.88	463.58	215.55	146.30	188.30	4578.21	748.86	282.09	233.12	2841.70	697.38	0.00		84102.04

APPENDIX 10

DEISS II ENERGY REPORT
NAVPGSCOL, MONTEREY, CA

Month	Apr		May		Jun	
	unit	cost	unit	cost	unit	cost
ELECTRIC	MWHRS	$	MWHRS	$	MWHRS	$
Mainstation	1366	90018.29	1359	121212.1	1352	139734
LaMESA	629	40473.84	612	40154.04	628	40200
ANNEX	1326	89432.58	1385	92117.46	1378	45965
NATURAL GAS	MBTU		MBTU		MBTU	
Mainstation	8593	28232.95	8912	28704.06	4219	12083.42
LaMESA	1475	8727.79	1266	7644.37	877	5795
ANNEX	0	0	0	0	5112	27508
FUEL OIL	MBTU		MBTU		MBTU	
Mainstation	4	20.72	2	18.92	3	15
LaMESA	0	0	0	0	0	0
ANNEX	29	157.18	29	151.2	43	224

APPENDIX 11


PW FISCAL DEPT. FORWARDS BUDGET ESTIMATES OF FY UTILITY COSTS TO COMPTROLLER
COMPTROLLER NOTIFIES USER OF ESTIMATED FY COST
USERS SEND FUNDS ON NAVCOMPT 2275 TO COMPTROLLER
COMPTROLLER RECORDS OBLIGATIONS AT BEGINNING OF MONTH
COMPT ASSIGNS JONS, RANGE OF SERIAL #s FOR EACH USER
INVOICE RECEIVED FROM SUPPLIER
INTERNAL DUE DATE ESTABLISHED BASED ON CONTRACT/PPA
INVOICES EXAMINED FOR PRIOR CHARGES ABNORMALLY HIGH CHARGES OR OTHER PROBLEMS
CERTIFICATION OF INVOICE NAVCOMPT 2035 PREPARED WITH NPS PAYING ALL CHARGES
NAVCOMPT 2035 FAXed TO AAA HARDCOPY MAILED
COMPTROLLER ADJUSTS OBLIGATIONS TO REFLECT ACTUAL AMOUNTS
COMPTROLLER ALLOCATES COSTS AMONG USERS BASED ON REVISED PROCEDURE
COST TRANSFERS EXECUTED TO REIMBURSE NPS FOR UTILITIES COSTS
COMPTROLLER PREPARES DAILY "STATUS OF REIMBURSABLES" REPORT

LIST OF REFERENCES

Bohi, Douglas R. Analyzing Demand Behavior: A Study of Energy Elasticities. Baltimore: The Johns Hopkins University Press, 1981.

Ricketts, Martin J. and Michael G. Webb. The Economics of Energy. London: The MacMillan Press Ltd., 1980.

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